Air Quality Permitting
Statement of Basis

August 17, 2005

Tier I Operating Permit No. T1-020041

Idaho Power Evander Andrews Complex

Mountain Home, ID

Facility ID No. 039-00024

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Air Quality Division

FINAL

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Acronyms, Units, and Chemical Nomenclature

AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
CAM	Compliance Assurance Monitoring
CEMS	continuous emissions monitoring systems
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
gr	grain
HAPs	Hazardous Air Pollutants
Hg	mercury
hr/yr	hours per year
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometer
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
MACT	Maximum Available Control Technology
mm	millimeters
MMBtu	million British thermal units
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
ng/J	nanograms per joule
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 micrometers or less
ppmvd	parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration
PTC	permit to construct
SIP	State Implementation Plan
SM	synthetic minor
SO_2	sulfur dioxide
T/yr	tons per year
TAPs	toxic air pollutants
UTM	Universal Transverse Mercator
VOC	volatile organic compound

Public Comment / Affected States / EPA Review Summary

A 30-day public comment period for the Evander Andrews Complex draft Tier I operating permit was held from July 13, 2005 through August 12, 2005 in accordance with IDAPA 58.01.01.364, *Rules for the Control of Air Pollution in Idaho.*

IDAPA 58.01.01.008.01, defines *affected states* as, "*All states: whose air quality may be affected by the emissions of the Tier I source and that are contiguous to Idaho, or that are within 50 miles of the Tier I source.*"

A review of the site location information included in the permit application indicates that the facility is not located within 50 miles of a state or tribal border. Therefore, the adjacent states and tribes were not be provided with a copy of the draft Tier I operating permit.

Summary of Comments: No comments were received from the public or from any affected state.

A hearing was not requested.

1. PURPOSE

The purpose of this memorandum is to satisfy the requirements of IDAPA 58.01.01.300, *Rules for the Control of Air Pollution in Idaho*, for issuing Tier I operating permits.

2. FACILITY DESCRIPTION

The Idaho Power Company (Idaho Power) operates the Evander Andrews Complex located near Mountain Home, Idaho. This is an electric power generating facility which utilizes two advanced Siemens-Westinghouse (S-W) 251B12A, simple cycle combustion turbines and generators. The heat input for each turbine is approximately 508 MMBtu/hr and the generating capacity is approximately 52 megawatts each. Both turbines are identical in design, fired only with natural gas, and are equipped with dry low NO_x (DLN) burners. DLN burners combust a leaner mixture of fuel and air, thereby lowering the peak temperature and NO_x emissions. During warm weather, evaporative cooling and inlet air fogging may be used to cool the turbine inlet air. Natural gas flow rates are measured continuously by a certified fuel flow monitoring system. Facility operations are monitored by an integrated microprocessor-based control system. Each combustion turbine is equipped with a continuous emissions monitoring system (CEMS) to measure NO_x, carbon monoxide (CO), and diluent oxygen (O_2). Also included is a data acquisition and handling system (DAHS) for data acquisition and analysis. These data systems are used during all facility operations, including startup and shutdown. Ancillary units at the facility include a natural gas-fired heater to heat the natural gas prior to combustion and a diesel-fired emergency fire pump.

The following is a list of the sources at the facility:

Gas Turbines:	Siemens-Westinghouse (S-W) 251B12A
Heat Input:	508 MMBtu/hr each, natural gas
Fuel Heater:	2.2 MMBtu/hr, natural gas
Emergency Fire Pump:	185 horsepower diesel, 500 hr/yr

3. FACILITY / AREA CLASSIFICATION

The Evander Andrews Complex is defined by IDAPA 58.01.01.008.10 as a major facility for Tier I permitting purposes because the facility's potential to emit (PTE) NO_x and CO exceed 100 tons per year. It is a not a designated facility as defined in IDAPA 58.01.01.006.27. The facility is not subject to Prevention of Significant Deterioration (PSD) requirements since the potential to emit is less than 250 T/yr. The Standard Industrial Classification (SIC) is 4911 which OSHA describes as *establishments engaged in the generation, transmission, and/or distribution of electric energy for sale*. The AIRS facility classification is "A," because the actual or controlled potential to emit (PTE) for NO_x and CO are each greater than 100 T/yr.

The facility is located within AQCR 63 and UTM zone 11. The facility is located in Elmore County which is designated as an attainment or unclassifiable area for all criteria pollutants (PM_{10}, CO, NO_x, SO_2, lead, and ozone). There are no Class I areas within 10 km of the facility.

The AIRS information provided in the Appendix defines the classification for each regulated air pollutant at the Evander Andrews Complex. This required information is entered into the EPA AIRS database.

4. APPLICATION SCOPE

Idaho Power applied for an initial Tier I operating permit for the Evander Andrews Complex.

4.1 *Application Chronology*

September 14, 2001	DEQ issued a PTC for the Evander Andrews Complex. Permit Condition 4.9 contained Tier I operating permit application requirements
August 21, 2002	DEQ issued a modified PTC for the Evander Andrews Complex
September 20, 2002	DEQ received a Tier I operating permit application from Idaho Power
November 18, 2002	The Tier I application was declared complete
December 2, 2002	DEQ received additional information for the Tier I application
May 12, 2004	DEQ issued a Draft Tier I permit to Idaho Power for review
September 30, 2004	DEQ received an application to modify the PTC for purposes of streamlining requirements in the Tier I permit
March 18, 2005	DEQ issued a final revised PTC
April 22, 2005	DEQ issued a Draft Tier I permit to Idaho Power for review
May 23, 2005	Idaho Power provided comments on the Draft Tier I permit
July 13, 2005	A public comment period was held from July 13, 2005 to August 12, 2005
August 26, 2005	EPA issued a letter stating the permit is now eligible for issuance.

5. PERMIT ANALYSIS

5.1 *Emissions Inventory*

Emissions from the proposed Mountain Home Power Station were estimated by the applicant in the PTC and Tier I permit applications using specific emissions data provided by Siemens-Westinghouse for the gas turbines, AP-42 emission factors for the fire pump, and manufacturer's data for the fuel heater. The emission estimates provided in the applications were reviewed and found to be consistent with DEQ methods. Annual emission rate estimates and annual permit limits are based on the Annual Average Temperature which is 51°F for the facility's proposed location. Conversely, the maximum "short term" emission rates and permit limits (lb/hr) are based on a temperature of 15° F which was selected to represent winter conditions when emissions and modeled impacts would most likely be the greatest. Estimates are also made at 95°F to represent summer conditions for air dispersion modeling. Summaries of the maximum emission estimates are given in Tables 1 and 2 below. Note that normal operation of the diesel-fired fire pump is limited by a permit condition which allows no more than 50 hours per year of operation, and this was based on the operations proposed in the PTC application. In the event of an emergency, the pump may be operated for its intended purpose even if the allowable run time is exceeded; in that case, the permittee would need to report the event in accordance with IDAPA 58.01.01.130.

Table 1. CONTROLLED EMISSIONS ESTIMATES

Source Description	CO		NO_x		PM / PM_{10}		SO_2		VOC	
	lb/hr	T/yr	lb/h	T/yr @ 51°F	lb/hr	T/yr @ 51°F	lb/hr	T/yr	lb/hr	T/yr
Combustion Turbine (CT2)	32	75	52	124	5.0	12	1.4	3.4	3.0	7.3
Combustion Turbine (CT3)	32	75	52	124	5.0	12	1.4	3.4	3.0	7.3
Combined Emissions From Both Turbines	64	150	104	248	10	24	2.8	6.7	6.0	14.5
Fuel Heater	0.065	0.17	0.33	0.84	0.016	0.042	0.002	0.005	0.017	0.0044
Emergency Fire Pump	2.54	.064	6.9	0.17	0.013	0.0033	0.096	0.0024	0.30	0.01
Total facility emissions	---	150	---	249	---	24	---	6.7	---	14.5

Several toxic air pollutants (TAPs) will also be released from the facility as a result of fuel combustion. Table 2 lists the estimates for toxics emitted above the screening emission levels specified in IDAPA 58.01.01.585 and 586. The ton-per-year emissions rates assume continuous operation of the emissions units. They are included for emissions inventory purposes only.

Table 2. TOXIC EMISSIONS ESTIMATES, FACILITY-WIDE TOTALS

Pollutant	Estimated Emissions (lb/hr)	DEQ Screening Emission Level (lb/hr)
Acetaldehyde	0.021	0.003
Arsenic	0.00070	1.5E-06
Benzene	0.014	0.0008
1, 3-Butadiene	0.00051	2.4E-05
Cadmium	7.0E-05	3.7E-06
Formaldehyde (annual average)	0.52	0.00051
Nickel	0.0051	2.7E-05
Sulfuric Acid	0.23	0.067

Since the estimated project emission rates of these TAPs are higher than the screening emission levels, modeling was conducted previously as part of the PTC process. When modeled in accordance with IDAPA 58.01.01.210.05, the ambient concentrations were found to be below the acceptable ambient concentrations for toxics listed in IDAPA 58.01.01.585. Therefore, in the PTC application, compliance with the TAPs standards under IDAPA 58.01.01.220 was demonstrated.

6. REGULATORY REVIEW; FACILITY- WIDE REQUIREMENTS

This section of the Statement of Basis describes the regulatory requirements for this PTC action.

6.1 Fugitive Particulate Matter - IDAPA 58.01.01.650-651

Permit Condition 2.1 states that all reasonable precautions shall be taken to prevent Particulate Matter from becoming airborne in accordance with IDAPA 58.01.01.650-651.

6.2 Compliance Demonstration

Permit Condition 2.2 states that the permittee is required to monitor and maintain records of the frequency and the methods used by the facility to reasonably control fugitive particulate emissions. The use of water or chemicals, applying dust suppressants, using control equipment, covering open-bodied trucks, paving roads or parking areas, and removing materials from streets are some examples listed in IDAPA 58.01.01.651.

Permit Condition 2.3 requires the permittee to maintain a record of all fugitive dust complaints received. In addition, the permittee is required to take appropriate corrective action as expeditiously as practicable after receipt of a valid complaint. The permittee is also required to maintain records that include the date each complaint was received, a description of the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

Permit Condition 2.4 requires the permittee to conduct periodic inspections of the facility to ensure that the methods being used are reasonably controlling fugitive emissions, even if a complaint has not been received. The permittee is required to inspect potential sources of fugitive emissions during daylight hours and under normal operating conditions. If the permittee determines fugitive emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee is also required to maintain records of the results of each fugitive emission inspection.

Permit Conditions 2.3 and 2.4 require the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of receiving a valid complaint, or determining that fugitive emissions are not being reasonably controlled, meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

6.3 Control of Odors - IDAPA 58.01.01.775-776

Permit Condition 2.5 and IDAPA 58.01.01.776 both state: "No person shall allow, suffer, cause or permit the emission of odorous gases, liquids or solids to the atmosphere in such quantities as to cause air pollution." This condition is currently considered federally enforceable until such time it is removed from the SIP, at which time it will be a state-only enforceable requirement.

6.4 Compliance Demonstration

Permit Condition 2.6 requires the permittee to maintain records of all odor complaints received. If the complaint has merit, the permittee is required to take appropriate corrective action as expeditiously as practicable. The records are required to contain the date each complaint was received, a description of the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

Permit Condition 2.6 requires the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of receipt of a valid odor complaint meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

6.5 Visible Emissions - IDAPA 58.01.01.625

Permit Condition 2.7 and IDAPA 58.01.01.625 state that "No person shall discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined . . ." by IDAPA 58.01.01.625.

This provision does not apply when the presence of uncombined water, NO_x, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this rule.

6.6 Compliance Demonstration

Permit Condition 2.8 requires the permittee to conduct routine visible emissions inspections of the facility to ensure reasonable compliance with the visible emissions rule. The permittee is required to inspect potential sources during daylight hours and under normal operating conditions. The inspection consists of a see/no see evaluation for each potential source. If any visible emissions are present from any point of emission covered by this condition, the permittee must either take appropriate corrective action as expeditiously as practicable, or perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is determined to be greater than 20% for a period or periods aggregating more than three minutes in any 60-minute period, the permittee must take corrective action and report the exceedance in its semiannual monitoring/deviation report, annual compliance certification, and in accordance with the excess emissions rules in IDAPA 58.01.01.130-136. The permittee is also required to maintain records of the results of each visible emissions inspection and each opacity test when conducted. These records must include the date of each inspection, a description of the permittee's assessment of the conditions existing at the time visible emissions are present, any corrective action taken in response to the visible emissions, and the date corrective action was taken.

Should an emissions unit have a specific compliance demonstration method for visible emissions that differs from Facility-wide Condition 2.8, then the specific compliance demonstration method overrides the requirement of this condition. Facility-wide Condition 2.8 is intended for small sources that would generally not have any visible emissions.

Permit Condition 2.8 requires the permittee to take corrective action as expeditiously as practicable. In general, DEQ believes that taking corrective action within 24 hours of discovering visible emissions meets the intent of this requirement. However, it is understood that, depending on the circumstances, immediate action or a longer time period may be necessary.

6.7 Excess Emissions; Startup, Shutdown, Scheduled Maintenance, Safety Measures, Upset, and Breakdown - IDAPA58.01.01.130-136

Permit Condition 2.9 requires the permittee to comply with the requirements of IDAPA 58.01.01.130-136 for startup, shutdown, scheduled maintenance, safety measures, upset, and breakdowns. This section is fairly self-explanatory and no additional detail is necessary in this technical analysis. However, it should be noted that subsections 133.02, 133.03, 134.04, and 134.05 are not specifically included in the permit as applicable requirements. These provisions only apply if the permittee anticipates requesting consideration under subsection 131.02 to allow DEQ to determine if an enforcement action to impose penalties is warranted. Section 131.01 states ". . . The owner or operator of a facility or emissions unit generating excess emissions shall comply with Sections 131, 132, 133.01, 134.01, 134.02, 134.03, 135, and 136, as applicable. If the owner or operator anticipates requesting consideration under Subsection 131.02, then the owner or operator shall also comply with the applicable provisions of Subsections 133.02, 133.03, 134.04, and 134.05." Failure to prepare or file procedures pursuant to sections 133.02 and 134.04 is not a violation of the *Rules for the Control of Air Pollution in Idaho* in and of itself, as stated in subsections 133.03.a and 134.06.b. Therefore, since the permittee has the option to follow the procedures in subsections 133.02, 133.03, 134.04, and 134.05, and is not compelled to, the subsections are not considered applicable requirements for the purpose of this permit and are not included as such.

Idaho Power provided documentation to address excess emissions scenarios in Section 6, pages 43-47, of the Tier I operating permit application. This information should be referred to in the event an excess emission event occurs at the facility. For convenience, a copy is included in the Appendix of this Statement of Basis.

6.8 Compliance Demonstration

The compliance demonstration is contained within the text of Permit Condition 2.9. No further clarification is necessary here.

6.9 Performance Testing

If testing is required, Permit Condition 2.10 section specifies the requirements and recommended actions for testing. The reference test methods for each regulated air pollutant are addressed in specific sections of the permit where they apply. Any deviation from a reference test method should be approved by DEQ in writing in prior to conducting the test. Failure to obtain prior written approval may result in DEQ determining the testing does not satisfy the testing requirements.

6.10 Monitoring and Recordkeeping

The permittee is required to retain all monitoring records and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application, as required by IDAPA 58.01.01.322.07.c. Though specific applicable requirements may have record retention times of less than five years, IDAPA 58.01.01.322.07.c requires the permittee to maintain all recorded data for a minimum of five years, which also satisfies those shorter record retention requirements.

6.11 Reports and Certifications

All periodic reports and certifications required by the permit shall be submitted within 30 days of the end of each specified reporting period, unless specified otherwise within the permit, to the appropriate DEQ regional office and EPA regional office as appropriate. The address for EPA's Acid Rain Division was included for reporting required by 40 CFR 72 through 78.

6.12 Fuel Burning Equipment – IDAPA 58.01.01.675

The fuel burning equipment requirements contained in IDAPA 58.01.01.728 apply only to the fuel heater at this facility. For details, refer to Section 7 of this regulatory analysis.

6.13 Fuel-Sulfur Content

The fuel-sulfur content requirements contained in IDAPA 58.01.01.728 apply only to fuels used in the diesel-fired emergency fire pump. For details, refer to the section of this regulatory analysis which addresses this source.

6.14 Open Burning

All open burning shall be done in accordance with IDAPA 58.01.01.600-616.

6.15 Renovation/Demolition

The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M, National Emission Standard for Asbestos when conducting any renovation or demolition activities at the facility.

6.16 Chemical Accident Prevention Provisions – 40 CFR 68

Any facility that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, must comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance is first present above a threshold quantity listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.

At the time of issuance of this permit, the facility did not have any regulated substances that exceed the threshold quantity and Part 68 does not apply.

6.17 Recycling and Emission Reductions

The purpose of 40 CFR 82, Subpart F is to reduce emissions of Class I and Class II refrigerants to the lowest achievable level during the service, maintenance, repair, and disposal of appliances in accordance with Section 608 of the Clean Air Act. Subpart F applies to any person servicing, maintaining, or repairing appliances, except for motor vehicle emissions. Subpart F also applies to persons disposing of appliances, including motor vehicle air conditioners.

6.18 PTC General Provisions

General Provision 2 from PTC No. P-040031 contains applicable requirements that apply to all units regulated in the Tier I operating permit. In addition, PTC General Provision 3 is an applicable requirement that is not completely addressed by Tier I General Provision 14. In particular, PTC General Provision 3 allows DEQ to require stack emission testing in conformance with IDAPA 16.01.01.157 when deemed appropriate by the Director. Therefore, these applicable PTC requirements were included in the facility-wide section of the Tier I operating permit.

6.19 NSPS (40 CFR 60)

The gas turbines are subject to 40 CFR 60, Subpart GG. This is addressed in the next section of this Statement of Basis.

For all NSPS-affected units, the owner or operator shall comply with the requirements of the general provisions in 40 CFR 60, Subpart A. These requirements are addressed below and in Section 3 of the Tier I operating permit. However, all requirements concerning opacity and continuous monitoring were omitted where they are not applicable with regard to NSPS Subpart GG.

40 CFR 60.4 states that Section 111(c) of the Clean Air Act directs the Administrator to delegate to each state, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such state. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate state agency of any state to which this authority has been delegated. However, note that 40 CFR 52 does not delegate authority for NSPS to the Idaho DEQ. Therefore, requirements were added to the Tier I permit for the facility to also send copies to DEQ of any submittals sent to EPA. This was added to the facility-wide permit conditions and to Section 3 of the Tier I permit under 40 CFR 60.4, as per IDAPA 58.01.01.322.08. The Tier I permit contains copies of applicable requirements from 40 CFR 60 Subparts A and GG which were current as of the time of issuance of the permit. In the event of any discrepancies between this document, the Tier I permit, and the applicable federal regulations, the federal regulations shall govern.

7. REGULATORY REVIEW; EMISSIONS UNITS

Combustion Turbines

7.1 Emissions Unit Description

Refer to the descriptions in the permit and in Section 2 of this Statement of Basis.

7.2 Permit Requirement – NO_x and CO Emission Limits, PTC NO. 039-00024

The PTC includes annual emissions limits for NO_x and CO from the turbines.

7.3 Compliance Demonstration

Idaho Power is required to install a NO_x continuous emission monitoring system (CEMS) to meet the Acid Rain program requirements of 40 CFR 75. A monitoring condition was also added to the permit to require this CEMS to be used for demonstrating compliance with the NO_x emission rate limits. To demonstrate compliance with the CO emission rate limits, installation of a CO CEMS is required as a monitoring condition in the PTC. The information from each CEMS will be used to continuously indicate the compliance status of each turbine's emissions with respect to the permit limit. To show compliance with the annual NO_x and CO emission limits, a monitoring condition was added to monitor and record the NO_x and CO emissions, based on the CEMS data, on a rolling 12-month basis. The permit also establishes quality assurance procedures for each CEMS. As an additional measure, the turbines are required to be fired using natural gas exclusively.

7.4 Permit Requirements – NO_x Emission Limit and Fuel Sulfur Content Limit, Gas Turbine NSPS, 40 CFR 60, Subpart GG

In accordance with 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, 40 CFR 60.332(a)(1), NO_x emissions, for each turbine, must not exceed: $STD = 0.0075(14.4/Y) + F$. Where STD is the allowable NO_x emissions percent by volume at 15% oxygen on a dry basis, F is the NO_x emissions allowance for fuel-bound nitrogen, and Y is the manufacturer's heat input rate. For each of the Evander Andrews Complex turbines, STD equals 142 ppmvd. In addition, fuel sulfur content must not exceed 0.8% by weight as per 40 CFR 60.333(b).

7.5 Compliance Demonstration

Compliance with the NO_x and sulfur limitations is demonstrated by following the NSPS requirements established for this purpose. The Tier I operating permit includes the these requirements as presented in the final revision to 40 CFR Part 60 Subpart GG that was issued by the EPA as a final rule on July 8, 2004. For NO_x, the primary compliance demonstration method is the CEMS. For the NO_x and SO_2 standards, compliance is also demonstrated by following the fuel monitoring requirements as specified by the Subpart GG revisions. In, particular, the sulfur and nitrogen content of the fuel must be monitored in accordance with 40 CFR 60.334(j) and (i), which includes the option of using the July 10, 2002 EPA-approved Custom Fuel Monitoring Schedule. A copy of this letter in included in the Appendix for reference.

Idaho Power demonstrated compliance during the initial NO_x and SO_2 performance tests conducted on February 25, 2002 per 40 CFR 60.335 and 60.8, and the permit contains a requirement to perform additional testing under this standard "upon request of the Administrator" as specified in 40 CFR 60.8.

It is also noted that the manufacturer's projected NO_x emissions rate from each turbine (30 ppmvd) has been achieved during normal operations, and this is much less than the NO_x emission limit allowed by Subpart GG (142 ppmvd).

Excess emission reporting under Subpart GG is addressed under 60.334(j). For purposes of reporting excess NO_x emissions under 60.334, an exceedance shall be any emissions from the gas turbine stack that exceed 142 ppmvd at 15% oxygen based on a "four-hour rolling average NO_x concentration". The NO_x CEMS may be used to determine if an exceedance occurs per 60.334. See the section below regarding Subpart GG excess emissions for additional details.

7.6 Visible Emissions - IDAPA 58.01.01.625

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity. This provision does not apply when the presence of uncombined water, NO_x, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this rule.

7.7 Compliance Demonstration

A visible emissions evaluation is required for each stack at the facility, including the gas turbine stack, on a monthly basis and in accordance with IDAPA 58.01.01.625. The compliance determination method for IDAPA 58.01.01.625 is Facility-wide Condition 2.8.

7.8 Permit Requirement – Fuel Sulfur Content, 40 CFR, Subpart GG

The SO_2 standard which applies to this facility is given by 40 CFR 60.333(b) and it specifies a fuel sulfur limit of 0.8% by weight.

7.9 Compliance Demonstration

Compliance with these requirements is demonstrated by following the NSPS fuel monitoring requirements as specified by 60.334 and 60.335.

7.10 Permit Requirement – NO_x Monitoring, Acid Rain Program, 40 CFR 75

Each turbine at the Idaho Power Evander Andrews Complex is an affected unit under 40 CFR 72.6(a)(3)(i) and must comply with the operating, monitoring, and recordkeeping requirements of 40 CFR 75.

7.11 Compliance Demonstration

Operating, monitoring, and recordkeeping requirements that demonstrate compliance with the federal Acid Rain Program are provided in 40 CFR 75, and the permit condition to follow these requirements was included in the PTC and the Tier I permit. Also see the Acid Rain Permit section of this document below.

7.12 Permit Requirement – Turbine NO_x and SO_2 Performance Tests, NSPS, 40CFR, Subpart GG

Idaho Power completed the initial performance test requirements on February 25, 2002 as required by 40 CFR 60.335 and 60.8. With regard to future tests under Subpart GG, the permit requires additional testing "upon request of the Administrator" as specified in 40 CFR 60.8.

7.13 Permit Requirement – Excess Emissions, NSPS, Subpart GG

The permittee is required to comply with the excess emissions requirements specified by 60.334(j) whenever NO_x emissions exceed the NSPS standard specified under 60.332(a)(1) and 60.332(b) (e.g., 142 ppmvd) based on a "four-hour rolling average NO_x concentration". Also, it is recognized that the requirement to install the NO_x CEMS is given by 40 CFR Part 75, not Part 60 Subpart GG (NSPS), and for this reason it is not necessary for Idaho Power to meet the requirements for "excess emissions and monitoring system performance reports" for the NO_x CEMS as specified by 60.7.

7.14 Federal Requirement – NSPS General Provisions, 40 CFR 60, Subpart A

40 CFR 60, Subpart A establishes the NSPS General Provisions which apply to both turbines in accordance with 40 CFR 60.1. These provisions were included in Section 3 of the permit unless noted otherwise below:

- 60.14(i) through 60.14(l), which apply to "repowering and coal fired projects, were not included in the permit since these requirements do not apply to the Evander Andrews Complex.
- 60.16, the NSPS *Priority List*, which refers to EPA's general NSPS priorities, was not included in the Tier I permit since it doesn't specifically apply to this facility.
- 60.18, *General Control Device Requirements*, applies only to flares. It was not included in the permit since it doesn't apply to the facility.

7.15 Compliance Demonstration

None required since this is not an applicable requirement for Idaho Power.

7.16 Federal Requirement – NSPS General Provisions, 40 CFR 61

None of the requirements under the National Emission Standards for Hazardous Air Pollutants (NESHAP), as given by 40 CFR Part 61,apply to this facility.

7.17 Federal Requirement – NSPS General Provisions, 40 CFR 63, Subpart YYYY

40 CFR 63, Subpart YYYY, was issued by the EPA as a final rule on March 5, 2004. Based on the TAPs PTE data in the Tier I application (Table 5-3, page 40), the Evander Andrews Complex is not a "major source of HAP emissions" as defined by 40 CFR 63.6085(b). Therefore, the turbine is not subject to Subpart YYYY per 63.6085 because it is not located at a "major source of HAP emissions."

7.18 Federal Requirement – Compliance Assurance Monitoring (CAM), 40 CFR 64

These regulations do not apply to the Evander Andrews complex per 40 CFR 64.2 since the facility does not utilize a control device(s) to achieve compliance with an emission limitation or standard.

7.19 Compliance Demonstration

None required since this is not an applicable requirement for Idaho Power.

Fuel Heater

7.20 Emissions Unit Description

Refer to the emissions unit descriptions provided in the permit.

7.21 Permit Requirement – Visible Emissions, IDAPA 58.01.01.625

The requirement that emissions may not exceed 20% opacity for more than three minutes in any 60-minute period applies to the fuel heater stack.

7.22 Compliance Demonstration

Compliance with the visible emissions standard for these two emission units is demonstrated by complying with Permit Condition 2.8.

7.23 Permit Requirement – Fuel Burning Equipment, IDAPA 58.01.01.676

The fuel heater was installed in January, 2002, therefore, it is subject to the particulate matter standard for new fuel-burning equipment. The grain-loading standard for natural gas combustion is 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume, per IDAPA 58.01.01.675.

7.24 Compliance Demonstration

It is reasonable to assume that compliance with the particulate matter standard is assured provided that only natural gas is combusted and the fuel heater is maintained in good working order and operated per manufacturer recommendations. According to AP-42, Section 1.4, July 1998, the burner would emit 7.6 pounds of particulate per million cubic feet of natural gas combusted. Also, according to 40 CFR 60, Appendix A, Method 19, Table 19-1, approximately 8,710 dscf of flue gas at standard conditions (68° F, 29.92 inches of Hg) is created per million British thermal units of natural gas. This data is used in the following steps to demonstrate that particulate emissions from the combustion of natural gas will always be less than the particulate matter standard of 0.015 gr/dscf.

Correct the flue gas volume as follows:

1) Altitude correction, IDAPA 58.01.01.680. (The facility altitude is 3,200 feet).

   Subtract 0.10 x 32.0 = 3.20 inches Hg from standard atmospheric pressure at sea level.
   29.92 inches Hg – 3.20 inches Hg = 26.72 inches Hg

2) Using the Ideal Gas Law and knowing that n, R, and T will be the same,

$$V_2 = \frac{P_1 V_1}{P_2} \tag{7.1}$$

where,

V_2 = the gas volume corrected for altitude,
V_1 = the known gas volume (8,710 dscf),
P_1 = the pressure of the known gas volume (29.92 inches Hg)
P_2 = the pressure of the corrected gas volume (26.72 inches Hg).

The altitude corrected volume (V_2) of the flue gas is 9,753 dscf.

For 3% oxygen:

Using a standard correction ratio as presented in 40 CFR 60, Appendix A, Method 19,

$$F_2 = F_1 \times \frac{20.9}{20.9 - 3.0} \quad (7.2)$$

where,

F_2 = the gas volume corrected to 3% oxygen,
F_1 = the altitude corrected flue gas volume (9,753 dscf) as calculated in Equation 5.1.

The oxygen and altitude corrected volume (F_2) of the flue gas is 11,388 dscf per million British thermal units of natural gas.

3) Determine the volume of flue gas created by the combustion of one million cubic feet of natural gas as follows:

$$10^6 \text{ feet}^3 \times 1{,}050 \text{ Btu/feet}^3 \times 11{,}388 \text{ dscf}/10^6 \text{ Btu} = 12.0 \times 10^6 \text{ dscf} \quad (7.3)$$

4) Determine the grain loading per cubic foot of flue gas as follows:

$$7.6 \text{ lb PM} \times 7{,}000 \text{ gr/lb} \div 12.0 \times 10^6 \text{ dscf} = 0.0044 \text{ gr/dscf} < 0.015 \text{ gr/dscf} \quad (7.4)$$

Emissions factors given in AP-42 are generally accepted as conservative estimates. Even a conservative estimate of emissions from natural gas combustion results in an approximated grain loading well below the standard of 0.015 gr/dscf. Therefore, as long as the permittee is in compliance with the permit condition requiring the exclusive use of natural gas, the permittee will be in compliance with the grain-loading standard.

7.25 Permit Requirement – Fuel Throughput Limit, PTC No. 039-00024, 8/21/02

The natural gas fuel throughput limitation for the fuel heater was included in the Tier I operating permit because this was a permit condition in the facility's PTC. This permit condition was included in the PTC because a restriction on the hours of operation was used in the modeling analysis performed for the PTC.

7.26 Compliance Demonstration

Compliance is demonstrated by complying with the monitoring and recordkeeping requirements included in the permit for natural gas fuel consumption in the fuel heater. The permittee must monitor the fuel consumption in cubic feet per year on a monthly and rolling 12-month basis.

Diesel-fired Emergency Fire Pump

7.27 Emissions Unit Description

Refer to the emissions unit description provided in the permit.

7.28 Permit Requirement – Visible Emissions, IDAPA 58.01.01.625

The requirement that emissions may not exceed 20% opacity for more than three minutes in any 60-minute period applies to the diesel engine stack.

7.29 Compliance Demonstration

Compliance with the visible emissions standard for this emission unit is demonstrated by complying with Permit Condition 2.8.

7.30 Permit Requirement – Hours of Operation, PTC No. 039-00024, 8/21/02

The PTC contains a restriction on hours of operation for the emergency fire pump, therefore, this applicable requirement was included in the Tier I operating permit. This permit condition was included in the PTC because a restriction on the hours of operation was used in the modeling analysis performed for the PTC. In the PTC analysis, it was demonstrated that emissions resulting from this amount of operation would be compliant with the NAAQS and TAPS requirements.

7.31 Compliance Demonstration

Compliance is demonstrated by complying with the monitoring and recordkeeping requirements included in the permit for hours of operation. The permittee must monitor the hours of operation for each source on a monthly and rolling 12-month basis.

7.32 Permit Requirement – Fuel Sulfur Content, IDAPA 58.01.01.728

No person shall sell, distribute, use, or make available for use any distillate fuel oil containing more than the percentages of sulfur allowed by the IDAPA 58.01.01.728.

7.33 Compliance Demonstration

For each load of fuel received at the facility, the permittee is required to maintain copies of documentation received from the supplier which shows the sulfur content of the distillate fuel.

8. TITLE IV ACID RAIN PERMIT

Idaho Power is subject to the acid rain permitting requirements of 40 CFR 72 through 75. The acid rain portion of the permit was drafted in the form of the EPA model permit based upon 40 CFR 72 and information previously provided by the EPA Acid Rain Division (see the 9-20-01 e-mail from R. Miller, EPA, to W. Russell, AirPermits.Com in the Appendix). The substance of the acid rain permit for Idaho Power is that the company must comply with the requirements listed on the Phase II application submitted to the EPA.

8.1 Emissions Unit Description

Refer to the emission unit descriptions provided in the permit. Both turbines at the Evander Andrews Complex are affected units under 40 CFR 72.6(a)(3)(i) and, therefore, each unit is subject to the Acid Rain Program.

8.2 Permit Requirement – Acid Rain Permit Contents, 40 CFR 72.50

The requirements for an Acid Rain Permit are listed in 40 CFR 72.50. The permit must contain the following: 1) all elements required for a complete Acid Rain permit application under 72.31, as approved or adjusted by the permitting authority; 2) the applicable Acid Rain emissions limitation for SO_2; 3) the applicable Acid Rain emissions limitation for NO_x; and 4) each Acid Rain permit is deemed to incorporate the definitions of terms under 72.2.

8.3 Compliance Demonstration

Compliance requirements are listed in the Acid Rain Permit application as included in the Tier I operating permit. Compliance with these requirements will assure compliance with the Acid Rain Program requirements.

8.4 Permit Requirement – SO_2 and NO_x Allowances, 40 CFR 73.2, 76.1

Idaho Power is subject to the provisions of Part 73 for SO_2 since it is an affected source pursuant to 72.6(a)(3)(i). The facility does not contain an affected source pursuant to 76.1since coal is not used for fuel, therefore, it is not subject to the provisions of Part 76 for NO_x. The facility is required to obtain SO_2 allowances in accordance with 40 CFR 72.9(c). The facility does not have a NO_x or SO_2 emission limit through these regulations. The substance of the regulation which applies to this facility is the requirement to monitor emissions and report the results.

8.5 Compliance Demonstration

Compliance with the Acid Rain Program requirements of is accomplished by complying with the requirements listed in the Acid Rain Permit application. The application requirements are included as part of the Acid Rain Permit as required by 72.50(a)(1).

9. INSIGNIFICANT ACTIVITIES

Insignificant activities are described in Section 5.1 of the Tier I permit application. This included the fuel heater and the diesel-fired emergency fire pump. Since these two units are subject to specific applicable requirements in PTC No. 039-00024, issued on August 21, 2002, they will not qualify as insignificant activities in accordance with IDAPA 58.01.01.317.01.

Table 3. INSIGNIFICANT ACTIVITIES

Emissions Unit	Description	Insignificant Activities IDAPA 58.01.01.317.01...
none	n/a	n/a

10. ALTERNATIVE OPERATING SCENARIOS

Inlet air fogging to reduce the temperature of the turbine inlet air is an alternative operating scenario.

11. TRADING SCENARIOS

No trading scenarios were proposed in the permit application.

12. COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION

12.1 Compliance Plan

Idaho Power has certified compliance with all applicable requirements and no outstanding compliance issues exist. No compliance plan is necessary.

12.2 Compliance Certification

Idaho Power is required to periodically certify compliance in accordance with General Provision 21 of the Tier I operating permit.

13. REGISTRATION FEES

Idaho Power is a major facility as defined in IDAPA 58.01.01.008.10 and is, therefore, subject to registration and registration fees in accordance with IDAPA 58.01.01.387. As of April 11, 2005, the balance of fees due from Idaho Power is $0.00.

14. RECOMMENDATION

Based on the Tier I application and review of federal regulations and state rules, staff recommends that Idaho Power be issued final Tier I operating permit No. T1-020041.

BR/KH/sd G:\Air Quality\Stationary Source\SS Ltd\T1\EvanderAndrews\Final\T1-020041 Final SB.doc

APPENDIX

Idaho Power, Evander Andrews Complex
Mountain Home

T1-020041

AIRS/AFS FACILITY-WIDE CLASSIFICATION DATA ENTRY FORM – EVANDER ANDREWS COMPLEX

AIR PROGRAM POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	TITLE V	AREA CLASSIFICATION A – Attainment U – Unclassifiable N – Nonattainment
SO_2	B	B				B	U
NO_x	A	SM	Yes – NO_x			A	U
CO	A	SM				A	U
PM_{10}	B	B				B	U
PT (Particulate)	B	B				B	U
VOC	B	B				B	U
THAP (Total HAPs)						B	
			APPLICABLE SUBPART				
			GG	none	none		

AIRS/AFS Classification Codes:

A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For NESHAP only, class "A" is applied to each pollutant that is below the 10 T/yr threshold, but which contributes to a plant total in excess of 25 T/yr of all NESHAP pollutants.

SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.

B = Actual and potential emissions below all applicable major source thresholds.

C = Class is unknown.

ND = Major source thresholds are not defined (e.g., radionuclides).

6.0 EXCESS EMISSION DOCUMENTATION

IDAPA regulations specific to Tier I operating permits require inclusion of excess emission documentation as part of the permit application. In this section, three types of excess emissions will be discussed for each emissions unit: startup, shutdown, and scheduled maintenance. Calculations and documentation for each potential excess emission will be provided. In addition, the expected frequency and justification for each excess emission occurrence will be discussed for each unit. Finally, any existing procedures for minimization of excess emissions will be identified.

6.1 EXCESS EMISSIONS — STARTUP

IDAPA 58.01.01.006.102 defines startup as "the normal and customary time period required to bring air pollution control equipment or an emissions unit, including process equipment, from a non-operational status into normal operation." A safety measure has been defined as "any shutdown (and related startup) or bypass of equipment or processes undertaken to prevent imminent injury or death or severe damage to equipment or property which may cause excess emissions" (*IDAPA 58.01.01.006.87*). The following subsections discuss startup excess emission conditions for the natural gas-fired combustion turbines (units CT2 and CT3), the natural gas fuel heater (H1), and the back-up emergency fire pump (FP1) located at IPC's Evander Andrews Complex.

6.1.1 Startup Emissions — Combustion Turbine Units CT2 and CT3

As previously stated in this application, CT2 and CT3 are identical units; therefore, the startup excess emission documentation for each unit will be the same. Potential startup excess emissions can occur for a variety of reasons, including initiation of safety measures, equipment malfunctions, fuel supply interruptions, and adverse environmental conditions.

Calculations and documentation for startup excess emissions are determined for units CT2 and CT3 using a CEMS. The CEMS uses unit-operating data, certified formulas, and calculations to report emissions data for NO_x, CO, and fuel flow, as well as hours of operation. This information is stored in a database. During unit startup, emissions data is recorded, flagged, and evaluated for excess emissions episodes. The CEMS incorporates warning and exceedance alarms for excess emissions on a computer console. During an alarm episode, plant personnel would acknowledge the CEMS episode using written quality assurance/quality control (QA/QC) procedures found in the site's CEMS QA/QC Manual. This manual also contains QA/QC procedures for the CEMS components.

Frequencies of startup excess emissions for the combustion turbine units are difficult to estimate. The potential excess emission situations described above would be caused by unexpected events and acts of God—it is impossible to predict when events such as these may occur. To minimize the occurrence of excess emissions due to unit startup, IPC will use written procedures and good operating practices.

6.1.2 Startup Emissions — Natural Gas Fuel Heater Unit H1

The natural gas fuel heater (H1) is limited by fuel flow. All emissions, including startup emissions, are therefore included as operational data. Operation of H1 is considered an insignificant activity under *IDAPA 58.01.01.317* regulations. An insignificant source is include in a Tier I permit application only to show that the facility is a minor source and that the facility is in compliance with applicable regulations. Therefore, H1 is not subject to Tier I excess emissions documentation. Excess emissions from H1 are not applicable, the following paragrap has been included to support this statement.

No reason is anticipated for startup excess emissions on H1. To create excess emission conditions, fuel in excess of the annual amount allowed by the PTC would have to be combuste in unit H1. This instance would constitute a PTC violation. All natural gas fuel combusted in the unit will be used to calculate the total heat input for the facility. IPC will use good operatin practices to minimize the occurrence of excess emissions from H1.

6.1.3 Startup Emissions — Back-up Emergency Fire Pump Unit FP1

The back-up emergency fire pump (FP1) is limited by operational hours. All emissions, including startup emissions, are therefore included as operational data. Unit FP1 will only be used during routine maintenance and emergency conditions (i.e., in the event of a power outage and fire at the facility). No reason is anticipated for startup excess emissions attributed to the back-up emergency fire pump. IPC will use good operating practices to minimize their occurrence.

6.2 EXCESS EMISSIONS — SHUTDOWN

Idaho air regulations define shutdown as "the normal and customary time period required to cease operations of air pollution control equipment or an emissions unit beginning with the initiation of procedures to terminate normal operation and continuing until the termination is completed" (*IDAPA 58.01.01.006.91*). A safety measure has been defined as "any shutdown (and related startup) or bypass of equipment or processes undertaken to prevent imminent injur or death or severe damage to equipment or property which may cause excess emissions" (*IDAP 58.01.01.006.87*). The following subsections discuss shutdown excess emission conditions for the natural gas-fired combustion turbines (units CT2 and CT3), the natural gas fuel heater (H1), and the back-up emergency fire pump (FP1).

6.2.1 Shutdown Emissions — Combustion Turbine Units CT2 and CT3

Shutdown excess emission documentation for each combustion turbine unit will be identical. Potential shutdown excess emissions can occur for a variety of reasons, including initiation of safety measures, equipment malfunctions, fuel supply interruptions, and adverse environmental conditions.

Calculations and documentation for shutdown excess emissions are determined for units CT2 and CT3 using a CEMS. The CEMS uses unit-operating data, certified formulas, and calculations to report emissions data for NO_x, CO, and fuel flow, as well as hours of operation. This information is stored in a database. During unit shutdown, emissions data is recorded, flagged, and evaluated for excess emissions episodes. The CEMS incorporates warning and exceedance alarms for excess emissions on a computer console. During an alarm episode, plant personnel would acknowledge the CEMS episode using written QA/QC procedures found in th site's CEMS QA/QC Manual.

No expected frequencies of shutdown excess emissions for the combustion turbine units are anticipated. The potential excess emission situations described above would be caused by unexpected events and acts of God—it is impossible to predict when events such as these may occur. To minimize the occurrence of excess emissions due to unit shutdown, IPC will use written procedures and good operating practices.

6.2.2 Shutdown Emissions — Natural Gas Fuel Heater Unit H1

The natural gas fuel heater (H1) is limited by fuel flow. All emissions, including shutdown emissions, are therefore included as operational data. Operation of H1 is considered an insignificant activity under *IDAPA 58.01.01.317* regulations. As stated in Section 6.1.2, H1 is insignificant source and included in the Tier I permit application only to show that the facility i in compliance. H1 is not subject to Tier I excess emissions documentation.

No reason is anticipated for shutdown excess emissions on H1. To create excess emission conditions, fuel in excess of the annual amount allowed by the PTC would have to be combuste in unit H1. This instance would constitute a PTC violation. All natural gas fuel combusted in the unit will be used to calculate the total heat input for the facility.

6.2.3 Shutdown Emissions — Back-up Emergency Fire Pump Unit FP1

The back-up emergency fire pump (FP1) is limited by operational hours. All emissions, including shutdown emissions, are therefore included as operational data. Unit FP1 will only b used during routine maintenance and emergency conditions (i.e., in the event of a power outage and fire at the facility). No reason is anticipated for shutdown excess emissions attributed to th back-up emergency fire pump. IPC will use good operating practices to minimize excess emissions.

6.3 EXCESS EMISSIONS — SCHEDULED MAINTENANCE

IDAPA 58.01.01.006.89 defines routine maintenance as "planned upkeep, repair activities and preventative maintenance on any air pollution control equipment or emissions unit, including process equipment, and including shutdown and startup of such equipment." The following subsections discuss scheduled maintenance excess emission conditions for the natural gas-fired combustion turbine units (CT2 and CT3), the natural gas fuel heater (H1), and the back-up emergency fire pump (FP1)

6.3.1 Maintenance Emissions — Combustion Turbine Units CT2 and CT3

The routine excess emission documentation for units CT2 and CT3 is identical; therefore, the discussion of these units has been combined below.

Excess emissions may occur during routine maintenance on the combustion turbines. The expected frequency is based on the individual unit's operating time, the number of unit startups, and the recommended maintenance schedule determined by the facility. The Evander Andrews Complex has incorporated written procedures to minimize and report excess emissions caused b routine maintenance as required by *IDAPA 58.01.01.133*. These procedures are found in the Continuous Emission Monitoring System Quality Control/Quality Assurance Program (Tetra Tech 2002).

Potential excess emissions that could occur during routine maintenance on CT2 and/or CT3 would exceed the permitted emission limits for NO_x and CO. Instances may occur when the units must be operated at conditions outside of normal operation for an extended time period to allow for tuning, system checks, preventative maintenance, or other activities (as defined by the manufacturer's recommendation for scheduled maintenance).

Calculations and documentation for scheduled maintenance excess emissions are determined fo units CT2 and CT3 using a CEMS. The CEMS uses unit-operating data, certified formulas, anc calculations to report emissions data for NO_x, CO, and fuel flow, as well as hours of operation. This information is stored in a database. During scheduled maintenance periods, emissions dat for each unit is recorded, flagged, and evaluated for excess emissions episodes. The CEMS incorporates warning and exceedance alarms for excess emissions on a computer console. During an alarm episode, plant personnel would acknowledge the CEMS episode using written QA/QC procedures. If an excess emission occurs, written procedures are followed that ensure compliance with *IDAPA 58.01.01.130-136*.

6.3.2 Maintenance Emissions — Natural Gas Fuel Heater Unit H1

The natural gas fuel heater (H1) is limited by fuel flow. All emissions, including all emissions from routine maintenance performed while the unit is running, are therefore included as operational data. Operation of H1 is considered an insignificant activity under *IDAPA 58.01.01.317* regulations. As stated in Section 6.1.2 of this application, H1 is not subject to Tie I excess emissions documentation.

No reason is anticipated for shutdown excess emissions on H1. To create excess emission conditions, fuel in excess of the annual amount allowed by the PTC would have to be combust in unit H1. This instance would constitute a PTC violation. All natural gas fuel combusted in the unit will be used to calculate the total heat input for the facility.

6.3.3 Maintenance Emissions — Back-up Emergency Fire Pump Unit FP1

The back-up emergency fire pump (FP1) is limited by operational hours. However, routine maintenance could cause an excess emission if operation of the fire pump was extended beyond the acceptable time period defined in the PTC. Although this situation is not expected, it might occur if the pump requires mechanical operation to troubleshoot or correct a problem. The Evander Andrews Complex has incorporated procedures to minimize and report excess emissions caused by routine maintenance as required by *IDAPA 58.01.01.133*.

UNI STATES ENVIRONMENTAL PROTECT AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

JUL 10 2002

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JUL 15 2002
DEPT. OF ENVIRONMENTAL C
TECHNICAL SERVICES OF

Reply To
Attn Of: OAQ-107

Mr. Peter Stewart
Idaho Power Company
PO Box 70
Boise, Idaho 83707

Re: NSPS, Subpart GG - Alternative Fuel Monitoring Plan, Mountain Home Generating Station, ORISPL 7953

Dear Mr. Stewart:

The purpose of this letter is to respond to Idaho Power Company (IPC) letter dated September 14, 2001, and e-mail dated April 8, 2002, which request the United States Environmental Protection Agency (EPA) to approve an alternative fuel monitorin plan for the two gas turbines at Mountain Home, Idaho. We understand the turbines are subject to the Acid Rain Program, an must comply with monitoring and reporting requirements of 40 CFR Part 75. EPA approves IPC's request, as described below.

Request No. 1: Request to use the procedures for fuel sulfur content determination in Section 2.3.3.1 of Appendix D to 40 CFR Part 75. Subpart GG sulfur requirements will be met by implementing Acid Rain Program requirements.

40 CFR §60.335(d) requires analysis of sulfur in gaseous fuels in accordance with ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-91. However, EPA approves your request to use the monitoring requirements for sulfur at 40 CFR Part 75. This alternative monitoring method can only be used when pipeline quality natural gas is the only fuel being burned, and it must b in accordance with 40 CFR Part 75, Appendix D, Section 2.3.

Request No. 2: Request for waiver of requirement to monitor the nitrogen content of the pipeline quality natural gas fuel. A Continuous Emission Monitoring System (CEMS) will be installed a each unit to measure and record nitrogen oxide, in accordance with 40 CFR Part 75.

Pursuant to 40 CFR §60.334(b)(2), IPC is required to monito turbines which combust pipeline quality natural gas as fuel, EP developed a National Policy, dated August 14, 1987, which allow the EPA regional offices to approve NSPS Subpart GG custom fuel monitoring schedules on a case-by-case basis. Based on the knowledge that there is no fuel-bound nitrogen, EPA Region 10 approves your request to waive the fuel gas nitrogen monitoring

These EPA approvals apply to the following two Siemens Westinghouse combustion turbines:

Unit 2 (Serial Number 46S8156-1), and
Unit 3 (Serial Number 45S8156).

These EPA approvals do not alter any of the other requirements of NSPS Subparts A and GG which may apply to the facility.

If you have any questions regarding this letter, please contact Mr. Harold Scott at (206) 553-1754.

Sincerely,

for
Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit

cc: Mr. Matthew Stoll, IDEQ
Ms. Rebecca Goehring, IDEQ

Source File
Idaho Power
Mt Home Power Statio

From: "Walt Russell" <wrussell@nwlink.com>
To: "Hanna, Ken (Idaho DEQ)" <khanna@deq.state.id.us>
Date: Thu, Sep 20, 2001 9:14 AM
Subject: Fw: Acid Rain

FYI. An acid rain permit is NOT required prior to start-up. The Phase II acid rain permit application is just as binding as the permit itself.

Walt

----- Original Message -----
From: <Miller.Robertl@epamail.epa.gov>
To: "Walt Russell" <wrussell@nwlink.com>
Sent: Thursday, September 20, 2001 7:35 AM
Subject: Re: Acid Rain

\>
\> Hey Walt:
\>
\> The standard requirements at 40 CFR 72.9, which should be included
\> verbatim in a Phase II Acid Rain permit, state that the owners and
\> operators shall "(1) operate the unit in compliance with a complete Acid
\> Rain permit application or (my emphasis) a superseding Acid Rain permit
\> issued by the permitting authority; and (2) have an Acid Rain permit" (see
\> 40 CFR 72.9(a)(2)(i) & (ii)).
\>
\> The regulatory language in part 1 of the above statement makes it
\> clear that it is permissible for a unit to operate if it has submitted an
\> Acid Rain permit application. The rules were written this way
specifically
\> for scenarios in which the permitting authority, for whatever reasons, was
\> not able to issue an Acid Rain permit before the source was ready to
\> commence operation. Yes, the above statement also states that a source
\> shall have an Acid Rain permit, but nowhere do the rules state that the
\> permit must be issued before the source commences operation.
\>
\> All of the title IV applicable requirements are included in a Phase
II
\> permit application, and the rules state at 40 CFR 72.32(c) that a complete
\> Acid Rain permit application is enforceable as an Acid Rain permit and is
\> legally binding on the owners and operators and the designated
\> representative until the Acid Rain permit is issued. Since there are no
\> additional title IV applicable requirements added to those included in the
\> Acid Rain permit application by the title V permitting authority when the
\> Acid Rain permit is issued, the owners, operators, and DR are legally
bound
\> by the submission of a complete Acid Rain permit application in exactly
the
\> same way they will be by the Acid Rain permit that will supersede it once
\> issued. It therefore makes little sense to me why a permitting authority
\> would insist that the Acid Rain permit must be issued before a source
\> commences operation.
\>
\> If anyone would like to discuss this with me, feel free to forward my
\> email and/or phone number and name to whoever is interested. I'm

available
> for conference calls on this matter as well. Thanks.
> ______________________________
>
> Robert Miller
> Clean Air Markets Division
> (202) 564-9077
>
>
>
>
> Walt Russell
> <wrussell@nwl To: RobertL
Miller/DC/USEPA/US@EPA
> ink.com> cc:
> Subject: Acid Rain
> 09/19/2001
> 06:23 PM
>
>
>
>
>
>
> Robert. I have recently received a draft air permit for a
> natural-gas-fired combustion turbine electric generating facility that is
> definitely subject to the acid rain provisions. The following statement
is
> in the draft air permit:
>
>
> " The source cannot operate the combustion units until their
> Phase II, Acid Rain permit has been issued."
>
>
> It is my understanding that the Phase II acid rain permit does not have to
> actually be issued by the time the facility starts operating. Rather the
> Phase II permit must have been applied for.
>
> Your clarification would be appreciated.
>
> Walt Russell
> wrussell@airpermits.com
>
>
>
>

CC: "Elliott, Mike (Ida-West)" <melliott@ida-west.com>...

NSPS Standard for Nitrogen Oxides

40CFR60.332(a)(1) Section 6.8 of Tech

$$STD = 0.0075\left(\frac{14.4}{Y}\right) + F$$

STD = allowable NOx emissions (% by volume at 15% oxygen dry basis)

Y = manufacturer's rated heat rate at rated load

For Gas Turbine with natural gas at base load

$$Y = \frac{11095\ Btu}{kW \cdot hr}\left(\frac{1055\ J}{1\ Btu}\right)\left(\frac{1\ kJ}{1000\ J}\right)\left(\frac{1\ kW}{1000\ W}\right) = 11.71\ \frac{kJ}{W \cdot h}$$

F = NO_x emission allowance for fuel bound nitrogen

from manufacturer's data fuel composition, 1.0707 % N_2

therefore $F = 0.005$ per 40 CFR 60.332(a)(3)

$$STD = 0.0075\left(\frac{14.4}{11.71}\right) + 0.005 = 0.0142\% = 142\ ppm$$

$324.

EMENS
stinghouse

Idaho Power
Expected [illegible] Combustion Turbine Performance
Simple Cycle / Dry Low NOx Combustor
[illegible] 60Hz / 0.90 Power Factor

CTT-[illegible] Rev.[illegible]
[illegible]

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8	CASE 9	CASE 10
CONDITIONS:										
L TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
D LEVEL	BASE	BASE	75%	60%	BASE	75%	60%	BASE	75%	60%
FUEL HEATING VALUE, Btu/lbm (LHV)	20,677	20,677	20,677	20,677	20,677	20,677	20,677	20,677	20,677	20,677
SS FUEL HEATING VALUE, Btu/lbm (HHV)	22,940	22,940	22,940	22,940	22,940	22,940	22,940	22,940	22,940	22,940
PORATIVE COOLER STATUS/EFFECTIVENESS	85%	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
IENT DRY BULB TEMPERATURE, °F	95.0	95.0	95.0	95.0	51.0	51.0	51.0	15.0	15.0	15.0
IENT WET BULB TEMPERATURE, °F	82.4	82.4	82.4	82.4	44.1	44.1	44.1	12.3	12.3	12.3
IENT RELATIVE HUMIDITY, %	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
OMETRIC PRESSURE, psia	13.054	13.054	13.054	13.054	13.054	13.054	13.054	13.054	13.054	13.054
PRESSOR INLET TEMPERATURE, °F	84.3	95.0	95.0	95.0	51.0	51.0	51.0	15.0	15.0	15.0
T PRESSURE LOSS, Inches of water (Total)	4.0	4.0	3.1	2.2	4.5	3.5	2.4	4.8	3.8	2.4
AUST PRESSURE LOSS, Inches of water (Total)	3.5	3.4	2.6	2.0	4.1	3.1	2.2	4.8	3.5	2.4
AUST PRESSURE LOSS, Inches of water (Static)	0.8	0.7	0.6	0.4	1.0	0.8	0.5	1.1	0.9	0.6
CTION FLUID	-	-	-	-	-	-	-	-	-	-
CTION RATIO	-	-	-	-	-	-	-	-	-	-
USTION TURBINE PERFORMANCE:										
SS POWER OUTPUT, kW	38,080	37,280	27,880	22,220	44,050	32,980	26,300	48,700	38,480	29,100
SS HEAT RATE, Btu/kWh (LHV)	10,945	11,085	11,980	13,415	10,540	11,135	12,405	10,415	10,770	11,815
SS HEAT RATE, Btu/kWh (HHV)	12,140	12,310	13,295	14,880	11,690	12,360	13,780	11,555	11,945	13,105
L FLOW, lbm/hr	[illegible]	[illegible]	16,120	14,490	22,470	17,770	15,790	24,090	19,010	[illegible]
CTION RATE, lbm/hr	-	-	-	-	-	-	-	-	-	-
T INPUT, mmBtu/hr (LHV)	426	414	333	298	465	367	327	[illegible]	383	344
T INPUT, mmBtu/hr (HHV)	475	460	370	331	516	408	362	[illegible]	438	382
AUST TEMPERATURE, °F	985	990	[illegible]	1,020	958	994	991	941	941	949
AUST FLOW, lbm/hr	1,142,987	1,119,087	[illegible]	[illegible]	1,241,[illegible]	1,088,[illegible]	900,070	1,338,[illegible]	1,161,874	947,679
AUST FLOW, MACFM	0.80	0.79	0.67	0.60	0.85	0.71	0.63	0.90	0.74	0.64
MATED AUXILIARY LOADS, kW	140	141	141	141	141	141	141	141	141	141
UST GAS COMPOSITION (BY % VOL):										
GEN	13.42	13.57	14.18	13.82	14.01	14.73	14.21	14.02	14.87	14.32
ON DIOXIDE	3.00	3.08	2.78	2.94	3.13	2.80	3.03	3.18	2.79	3.05
ER	10.05	9.61	9.00	9.39	6.92	6.28	6.74	6.39	5.63	6.13
OGEN	72.54	72.85	73.05	72.93	75.00	75.25	75.07	75.45	75.75	75.56
ON	0.91	0.91	0.92	0.92	0.94	0.94	0.94	0.95	0.95	0.95
ECULAR WEIGHT	28.14	28.19	28.22	28.20	28.40	28.53	28.50	28.55	28.60	28.57
MISSIONS: Based on Westinghouse 21T[illegible] test methods										
ppmvd @ 15% O2	25	25	25	30	25	25	30	25	25	30
lbm/hr as NO2	44	43	34	37	48	38	40	52	40	43
ppmvd @ 15% O2	25	25	25	30	25	25	30	25	25	30
lbm/hr	27	26	21	23	29	23	25	32	25	26
ppmvd @ 15% O2 as CH4	2.0	2.0	5.0	6.0	2.0	5.0	5.0	2.0	5.0	5.0
lbm/hr as CH4	1.2	1.2	2.4	2.6	1.3	2.6	2.6	1.5	2.6	3.0
ICULATES, lbm/hr	2.1	2.0	1.8	1.5	2.3	2.1	1.7	2.5	2.2	1.8

Notes:
Performance based on new and clean condition.
All data is expected and not guaranteed.
Gross power output is at the generator terminals minus excitation losses.
Expected CT Performance values are dependent upon receiving test tolerances pursuant to the latest revision of SWPC EC- [illegible].
Actual exhaust flow can deviate from the calculated numbers.
Emission flowrates are calculated based on the maximum achievable exhaust flow. For further details on flowrate calculation contact SWPC.
VOC's are non methane, non ethane.
Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
Gas fuel composition is [illegible]% CH_4, [illegible]% C_2H_6, [illegible]% C_3H_8, [illegible]% iC_4H_{10}, [illegible]% nC_4H_{10}, [illegible]% iC_5H_{12},
[illegible]% nC_5H_{12}, [illegible]% nC_6H_{14}, [redacted] [illegible]% CO_2, 0.2 grains of sulfur per 100 SCF.
Gas fuel must be in compliance with the [redacted] Westinghouse Gas Fuel Spec ([illegible] Rev.[illegible]).
Liquid condensable fuels must be removed from the fuel lines.
Particulates are per US EPA Method 5B (front half only).
The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or
Environmental Impact Statement are strictly the responsibility of the Owner.
Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
Average temperature of the gas fuel is [illegible] °F.
Auxiliary loads are dependent on the final plant configuration.
Actual IGV schedule may vary. Part load performance will be adjusted accordingly.
Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.